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Patricia Banks Morrison
Senior Counsel

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SC PUBLIC SERVICE COMMISSION

September 22, 2005

VIA HAND DELIVERY

The Honorable Charles Terreni
Chief Clerk/Administrator
South Carolina Public Service Commission
101 Executive Center Drive
Columbia, South Carolina 29210

RE: South Carolina Electric & Gas Company – Annual Review of the Purchase Gas Adjustments and Gas Purchasing Policies
Docket No. 2005-5-G

Dear Mr. Terreni:

Enclosed for filing on behalf of South Carolina Electric and Gas Company, is the Direct Testimony of Kenneth R. Jackson, Martin K. Phalen, Harry L. Scruggs and Michael P. Wingo. Please accept the original and twenty-five (25) copies of each for filing. Additionally, please acknowledge your receipt of these documents by file-stamping the extra copies that are enclosed and returning them to me via my courier.

By copy of this letter, I am serving all other parties of record with a copy of the enclosed Direct Testimony and attach a certificate of service to that effect.

If there are any questions regarding this matter, please do not hesitate to contact me.

With kind regards,

Patricia B. Morrison

PBM/kwh
Enclosure

cc: Wendy Cartledge, Esquire
Scott Elliott, Esquire

CERTIFICATE OF SERVICE VIA HAND DELIVERY

I hereby certify that on September 22, 2005, a copy of South Carolina Electric & Gas Company's Direct Testimony of Kenneth R. Jackson, Martin K. Phalen, Harry L. Scruggs and Michael P. Wingo was served on the parties listed below via hand delivery at the addresses indicated:

Wendy Cartledge
Office of Regulatory Staff
1441 Main Street, Suite 300
Columbia, SC 29201

Scott Elliott, Esquire
South Carolina Energy Users Committee
Elliott & Elliott, P.A.
721 Olive Street
Columbia, SC 29205

Katherine Holland

RE: Docket No. 2005-5-G – South Carolina Electric & Gas Company's Annual Review of Purchased Gas Adjustments and Gas Purchasing Policies

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SC PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF
KENNETH R. JACKSON
ON BEHALF OF
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DOCKET NO. 2005-5-G

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Kenneth R. Jackson, 1426 Main Street, Columbia, South Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Director of Rates and Regulatory Affairs at SCANA Services, Inc.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I am a graduate of the University of South Carolina ("USC") where I received a Bachelor of Science Degree in Business Administration, majoring in Finance. Since graduating from USC, I have completed numerous graduate level courses in Business and Economics. I joined South Carolina Electric & Gas Company ("Company" or "SCE&G") in September 1978, where I held various positions within the Rate Department over the next eighteen years. In May 1997, I became Team Leader for Industrial Marketing. In October 1997, I was promoted to Manager of Marketing Research and Sales for the Large Customer Group. In July 1999, I was promoted to Assistant Controller for the Fossil and Hydro Strategic Business Unit ("SBU"). In May 2005, I became Director of Rates and

Regulatory Affairs. I also currently serve as the Chairman of the Accounting and Finance section of the Southeastern Electric Exchange.

Q. WILL YOU BRIEFLY SUMMARIZE YOUR DUTIES WITH SCANA SERVICES, INC.?

A. I am responsible for the design and administration of the Company's electric and gas rates and tariffs, including the electric fuel adjustment and gas cost adjustment. In addition, I am responsible for the Company's electric and gas cost of service studies, rate design, and regulatory accounting function.

Q. HAVE YOU PRESENTED TESTIMONY TO THIS COMMISSION BEFORE?

A. I have testified before this Commission in numerous previous proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide the Commission with information concerning the changes to the administration of the Purchased Gas Adjustments process that are reflected in the Settlement Agreement entered into by the Parties to Docket No. 2005-113-G on August 10, 2005 ("Settlement Agreement" or "Settlement").

Q. PLEASE EXPLAIN.

A. On April 26, 2005, SCE&G filed an Application for an adjustment in the rates and charges for its gas distribution service and for changes in its terms and conditions of service. This was the first gas rate case SCE&G had filed in sixteen years. As part of the application, SCE&G proposed several important changes in how it allocates gas costs for rate making purposes, and also proposed changes in related matters such as how it recovers environmental clean-up costs related to its former manufactured gas plant sites. These PGA changes and related adjustments were an integral part of the approach to pricing gas service contained in the rate case filing.

On August 10, 2005, all parties to the rate proceeding entered a comprehensive settlement which included a stipulation to the adjustments related to recovery of gas costs and environmental costs. If the Settlement is approved, the resulting rate changes and cost of gas adjustment change will take effect simultaneously with the PGA adjustments at issue here. The purpose of my testimony is to describe the changes in the PGA that will result from approval of the Rate Case Settlement.

Q. WHAT ARE THE PRINCIPAL CHANGES RELATED TO THE COST OF GAS CALCULATION CONTAINED IN THE SETTLEMENT?

A. Two principal changes in the cost of gas calculation are being proposed:

1. The first change relates to how the fixed upstream costs of delivering gas to SCE&G's system are allocated among customer classes for recovery through the Purchased Gas Adjustment ("PGA") factor. Presently, all firm customer classes pay the same PGA factor, which means they pay the same

cost per therm for capacity on upstream pipelines. The cost per therm is the same for all customer classes despite the fact that they place very different peak day demands on the system and so require very different levels of upstream capacity to support their demands. Under the Settlement, upstream capacity costs will be allocated among customer classes based on the peak design day demand each customer class places on the system, which more accurately reflects the demand-related nature of these costs.

2. The second change relates to net revenues (as described below) from interruptible service. Per the Settlement, the Company will directly allocate to firm customers the net revenues derived from its interruptible gas service. In the past, interruptible sales were considered in determining when rate adjustments were required, but there was no mechanism for directly allocating the benefit of interruptible sales to firm customer classes. Under the Settlement, the Company will pass the net interruptible margins through to firm customers in a transparent way by means of a credit to the cost of gas that will be computed in each PGA proceeding, and will be tracked as part of the monthly calculation of over or under collections.

Q. HOW WILL THE NEW PGA METHODOLOGY ALLOCATE UPSTREAM SUPPLY COSTS AMONG CUSTOMER CLASSES?

A. Under the Settlement, SCE&G will divide the current Purchased Gas Adjustment factor into (1) a commodity component which reflects the cost of gas commodity only (referred to in the tariff as the "Firm Commodity Benchmark"), and (2) a demand component which reflects the fixed charges on upstream pipelines (referred to in the tariff as the "Demand Charges" component). All firm customers would be charged the same Firm Commodity Benchmark. However, the Demand Charges component will be calculated for each customer class based on its contribution to peak design day demand. Added together, these two components – the Firm Commodity Benchmark and the class-specific Demand Charges component – will equal the PGA factor for each customer class.

Q. HOW DOES THIS METHOD COMPARE TO THE CURRENT METHOD OF CALCULATING THE PGA FACTOR?

A. Currently, the Company calculates a single PGA factor for all customer classes. Under the Settlement, there will be a separate PGA factor for each of the three customer classes.

Q. HOW WILL THE COMPANY TRACK THESE COMPONENTS ON A MONTHLY BASIS?

A. SCE&G will track these components very much the same way it tracks the monthly over and under collections under the single-factor PGA presently in use.

Currently, after the close of each month, the Company compares the actual commodity costs for the month and the actual costs incurred for upstream assets, to the actual amounts recovered during that month through the PGA factor. Any over or under collection is calculated and carried forward for crediting or recovery in the next PGA proceeding.

Under the Settlement, monthly over and under balances would continue to be calculated. However, the calculation would be done separately for the Firm Commodity Benchmark and for the Demand Charges component. These monthly over and under calculations would generate individual over or under balances for each customer class. Each customer class would carry forward its own net balance of over and under collections into the next PGA proceeding. ORS will monitor and verify these calculations on a monthly basis, and audit them annually.

Q. PLEASE EXPLAIN THE NET INTERRUPTIBLE REVENUE CREDITS.

A. Under the Settlement, SCE&G will credit directly to firm customers the net revenue it earns from interruptible sales. Specifically, the calculation of the Demand Charges component for each customer class will include a credit equal to an appropriate allocation of the net revenue that SCE&G derives from interruptible sales.

Q. HOW WILL SCE&G COMPUTE THE NET INTERRUPTIBLE REVENUE CREDITS FOR THE FIRM COST OF GAS CALCULATION?

A. The net interruptible revenue credits will equal the revenue generated from interruptible sales less a) the average commodity cost of gas for that month, and b) $0.02081/therm which reflects SCE&G's direct cost of providing service to interruptible customers.

Actual interruptible revenue credits generated would be considered as part of the over and under collection calculations each month. Net over and under collections would be used in setting the PGA for the ensuing period. ORS will monitor and verify these calculations on a monthly basis, and audit them annually.

This new mechanism will fairly reflect cost causation in allocating both the expense of upstream capacity and the value of interruptible sales. It will create a direct, fair and easy-to-understand link between interruptible sales and the benefits they provide firm customers and will function well under the Rate Stabilization Act recently adopted by our legislature.

Q. HOW WILL THIS NEW PGA METHODOLOGY CHANGE SCE&G'S ISP-R PROGRAM?

A. SCE&G would continue to bid competitive gas prices to its customers who have alternative fuel sources. Those bids would be based on the as-fired price of the customer's alternative fuel. The new cost of gas calculation will not change the ISP-R program as far as alternative fuel customers are concerned. The new calculations only change how costs and net margins (net interruptible revenue credits) are accounted for after sales are made, as described above.

Q. WHAT IMPACT WILL THE SETTLEMENT HAVE ON THE ENVIRONMENTAL CLEAN-UP FACTOR?

A. Under the Settlement, the Company will cease to collect the Environmental Clean-Up Cost ("ECC") factor initially approved in Order No. 94-1117. That order allowed the Company to defer costs related to environmental investigation and remediation at its former manufactured gas plant ("MGP") sites and recover them through a specific ECC factor applied on each therm of gas sold. Under the Settlement, the Company will collect these costs through base rates, recovering some costs as normal operating expenses and deferring others to be amortized into rates using a fixed amortization expense included in base rates. The current balance in the ECC account will be amortized along with additional deferrable ECC expenses which will be added to the account as they are recognized. Under the Settlement, the amounts accrued and the amounts collected through amortization will be audited and reviewed annually under the provisions of the Natural Gas Rate Stabilization Act. There will no longer be an ECC factor subject to audit and review in the PGA context.

Q. WHAT ACTION ARE YOU REQUESTING THAT THE COMMISSION TAKE IN THIS PROCEEDING?

A. The Company requests that the Commission set the PGA factor individually for each customer class using the methodology agreed to by the parties in the rate case Settlement. The Company specifically requests that the Commission authorize the process of crediting net interruptible revenues to the Demand Charges cost of gas factor for firm customers and reflect in its order in this proceeding the termination of the ECC factor. The Company also requests that the new PGA factors take effect simultaneously with the adjustments order in the Docket 2005-113-G, i.e. that they take effect for bills rendered on and after the first billing cycle of November 2005.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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SC PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY

OF

HARRY L. SCRUGGS

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2005-5-G

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Harry L. Scruggs, 1426 Main Street, Columbia, South Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Senior Rate and Regulatory Specialist in the Gas Rate Department of SCANA Services, Inc.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I am a 1979 graduate of Erskine College where I received a Bachelor of Arts Degree in Mathematics. I was hired in June of that year by Carolina Pipeline Company as a gas control operator where I worked seven years. In August 1986, I went to work for SCE&G as an analyst in their Load Research Department. In February 1988, I was assigned to my current position. I have developed and assisted in the development of cost of service studies, gas cost recovery mechanisms, allocation methodologies, rate analyses, and rate design.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION?

A. Yes, on a number of occasions.

Q. WILL YOU BRIEFLY SUMMARIZE YOUR DUTIES WITH SCANA SERVICES?

A. I am responsible for the preparation and development of the Company's gas cost of service studies, gas rate design, gas quarterly return on common equity filings and gas cost analyses.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to 1) describe the changes to the Company's cost of gas mechanism, 2) provide the cost of gas data, including the over / under collection amount, for the historical period under review in this proceeding, which is September 2004 through August 2005 and 3) provide the computations for the projected cost of gas per therm for the future period September 2005 through October 2006 including the impact of an increase in the cost of gas due to the increase in the subscription amount with our supplier. On behalf of the Company, I will request a) a firm commodity benchmark cost of gas component, and b) separate demand cost of gas components for the residential, general service and large general service usage groups to be included in our published tariffs for firm service, beginning with the first billing cycle for November 2005.

Changes to PGA Mechanism / Cost of Gas Data and Review / Projection

Q. HAS THE COMPANY PROPOSED CHANGES TO HOW THE COST OF GAS FACTOR IS COMPUTED?

A. Yes. The changes bifurcate the cost of gas between the commodity component, known as the Firm Commodity Benchmark, and the Demand Charge component. They also reflect the crediting of interruptible margin credits (IMC) to the firm customer demand cost of gas or DCOG. Details have been discussed in the pre-filed testimony of Mr. Kenneth R. Jackson in this Docket No. 2005-5-G. The testimony that follows reflects these new calculations. I will also testify to changes in the Over / Under collection mechanism.

Q. HAS THE METHODOLOGY FOR FORECASTING THE COST OF GAS CHANGED?

A. No. The Company's forecasting methodology, reviewed by the Commission in Docket 2004-5-G, remains unchanged for the period forecasted through the current proceeding.

Q. PLEASE EXPLAIN EXHIBIT NO. _____(HLS-1)?

A. Our current Purchased Gas Adjustment (PGA) factor was based on projections made in October 2004 and implemented the first billing cycle of November 2004. Exhibit No. ____(HLS-1) shows the under-collection resulting from the actual cost of gas being higher than the PGA factor charged to customers. This under-collection is projected to be $14,112,505 as of the end of the October 2005 billing month.

Q. DESCRIBE THE STARTING POINT FOR PROJECTING THE COMPANY'S FUTURE COST OF GAS?

A. The historic actual firm cost of gas and its associated billing determinants for the period September 1, 2004 through August 31, 2005 is the starting point. The basis is the monthly bills received by the Company from our supplier, South Carolina Pipeline Corporation, for each month's purchases. Both cost of gas components, commodity and demand, are included in these bills.

Q. HOW WAS THE TOTAL COMMODITY COST OF GAS PROJECTED?

A. First, the projected commodity cost of our supplier for the billing periods November 2005 through October 2006 was developed using New York

Mercantile Exchange ("NYMEX") index prices for this future twelve month period. These prices were adjusted for shrinkage, non-gas surcharges and commodity mark-ups. Next, the prices were applied to our supplier's historical purchases and a total Commodity Cost of Gas (CCOG) for our supplier was developed. Our supplier's CCOG by month was then multiplied by SCE&G's historic purchases to develop SCE&G's total CCOG, which includes any additions or subtractions for projected Price Risk Adjustments (PRA). These SCE&G CCOG monthly amounts were then divided by historic actual sales to calculate a CCOG price per therm.

Q. PLEASE EXPLAIN EXHIBIT NO. _____ (HLS-2)?

A. This exhibit contains the calculation of the Company's projected monthly firm and interruptible purchased CCOG. The monthly CCOG price projected for SCE&G, as described above, is multiplied by SCE&G's applicable projected therm sales resulting in the projected firm CCOG of $255,055,783 and the projected interruptible CCOG of $239,122,804. By dividing the projected firm CCOG by projected firm sales for the forecast period of November 2005 through October 2006, a price of $1.17903 per therm is derived. Dividing SCE&G's projected under-collection of $14,112,505 by the same projected firm sales develops a rate per therm of $0.06524 cents per therm. The sum of these two charges produces the total firm commodity rate per therm or Firm Commodity Benchmark of $1.24427 per therm.

Q. PLEASE GIVE THE COMPANY'S PEAK DESIGN DAY DEMAND FOR THE COMING 2005-6 WINTER SEASON AND EXPLAIN ITS IMPACT ON THE ALLOCATION OF THE DCOG.

A. SCE&G has a forecast Peak Design Day Demand (PDDD) of 353,598 dekatherms for the 2005-6 winter season. As seen in Exhibit No.____(HLS-3), the Residential, Small / Medium General Service (SGS / MGS) and Large General Service (LGS) groups are responsible for specific percentages of the PDDD and these percentages are used to allocate the projected DCOG.

Q. HOW DID YOU ARRIVE AT THE PROJECTED DCOG?

A. First, the forecast of interstate demand charges was made using the billing units from the historic period updated for anticipated pricing changes. This amount is $22,104,140 as seen in Exhibit No.____(HLS-3). Next, a quantification of our suppliers intrastate demand charges was made by applying the current price to the projected subscription amount. This subscription was determined in the following manor. Subtracting SCE&G's current contract of 276,495 dekatherms from their PDDD of 353,598 dekatherms leaves a balance of 77,103. An agreement between SCE&G and SCPC has been signed by both parties increasing SCE&G's DS-1 contract by 36,693 to 313,188 dekatherms. An Resale Firm Transportation Peaking (RFTP) agreement was also signed with SCPC for the amount of 40,410 dekatherms. Both agreements are anticipated to be effective December 1, 2005 meaning only 11 months of these costs are represented in the PGA forecast. The combination of the two amounts covers the balance of 77,103 dekatherms with both volumes being priced the same as current DS-1 capacity with SCPC of $3.5924 per dekatherm per month. The annual cost of these two increases totals $3,046,833. The RFTP will be coupled with capacity currently held and paid for by SCE&G's Electric Department (Electric) for use at its Jasper County electric generation facility. SCE&G's Gas Department (Gas) will share 40,410 dekatherms (41,235 dekatherms at purchase level) capacity with electric splitting the monthly cost of $10.672 per dekatherm per month for a total annual cost to Gas of $2,420,330.

Q. PLEASE DESCRIBE THE CALCULATION OF THE INTERRUPTIBLE MARGIN CREDITS TO FIRM CUSTOMERS?

A. A forecast of total interruptible margin revenue was calculated based on projected interruptible therm throughput of 218,095,000 therms multiplied by the projected margin per therm of $.07. This results in a total margin revenue generated by the interruptible class of $15,266,650. Next, the amount equal to $.02081 per therm, representing SCE&G's interruptible cost of service, is deducted from this amount. The difference in these amounts is $10,728,093 and will be known as the Interruptible Margin Credit (IMC) and passed on to the firm customer group as a credit to their DCOG.

Q. PLEASE EXPLAIN THE METHODOLOGY USED FOR NETTING THE DCOG WITH THE INTERRUPTIBLE MARGIN CREDITS AND SUBSEQUENTLY ALLOCATING THIS NET AMOUNT TO THE FIRM USAGE GROUPS.

A. Total projected DCOG for the forecast period of November 2005 through October 2006, consisting of the costs discussed above is $39,490,670 as seen in Exhibit No._____(HLS-3). The gross DCOG is netted for the projected amount of IMC and this net amount of $28,762,577 is then allocated on the PDDD usage group percentages. The Residential group is allocated at 73.30%, the SGS / MGS group at 22.65% and the LGS group at 4.05%.

Q. HOW ARE THE DCOG FACTORS AND TOTAL COST OF GAS FACTORS CALCULATED?

A. The allocated DCOG charges, as described above, are weighted by the projected monthly sales for each group resulting in the per therm DCOG factor. As seen in Exhibit No.____(HLS-4), the Residential DCOG factor is $0.16073 per therm, the SGS / MGS DCOG factor is $0.08331 per therm and the LGS DCOG factor is $0.05863 per therm. The sum of the Firm Commodity Benchmark and the DCOG factor results in the total cost of gas factor which is different for each of the Firm usage groups.

Q. WHAT COST OF GAS COMPONENTS ARE YOU REQUESTING THAT THE COMMISSION APPROVE AT THIS TIME?

A. We would like to request approval of a Firm Commodity Benchmark of $1.24427 per therm as well as the DCOG factors discussed above. When summed, the Firm Commodity Benchmark and DCOG factors produce total cost of gas factors of $1.40499 per therm for the Residential group, $1.32758 per therm for the SGS / MGS group and $1.30289 per therm for the LGS group.

Q. WHAT OVER / UNDER COLLECTION BALANCE ARE THESE RATES PROJECTED TO RETURN?

A. These factors are designed to return an over / under collection balance of approximately zero if sales and prices follow projections.

Q. WHAT IS THE COMPANY'S CURRENTLY APPROVED RATE FOR COST OF GAS?

A. The current cost of gas of $.90347 per therm was approved in Commission Order No. 2005-79, dated July 1, 2005, and was applied to the first billing cycle of November 2004 for all firm customers.

Q. IF THE PREVIOUS METHODOLOGY WERE USED TO CALCULATE THE PGA FACTOR WHAT WOULD THIS FACTOR BE?

A. The factor would be $1.46196 per therm for all Firm usage groups.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit No.___(HLS-1)

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
UNBILLED REVENUE REPORT

		GAS COST RATE/THERM (COL.1)	APPROVED FIXED RATE/THERM (COL.2)	DIFFERENCE (COL.3) (1-2)	ACTUAL FIRM SALES THERMS (COL.4)	(OVER)/UNDER COLLECTION (COL.5) (3*4)	PRIOR MONTH ADJUSTMENT (COL.6)	CUMULATIVE (OVER)/UNDER COLLECTION (COL.7) (5+6)
BEGINNING BALANCE ---								($5,405,742)
Nov-04	ACTUAL	$1.38944	$0.90347	$0.48597	12,773,251	$6,207,353.00	$74,605.00	$876,216
Dec-04	ACTUAL	$1.28390	$0.90347	$0.38043	27,389,172	$10,419,581.00	($151,144.00)	$11,144,653
Jan-05	ACTUAL	$0.83133	$0.90347	($0.07214)	35,946,249	($2,593,234.00)	$259,512.00	$8,810,931
Feb-05	ACTUAL	$0.68856	$0.90347	($0.21491)	39,319,677	($8,450,270.00)	$391,275.00	$751,936
Mar-05	ACTUAL	$0.76966	$0.90347	($0.13381)	31,607,234	($4,229,459.00)	$127,514.00	($3,350,009)
Apr-05	ACTUAL	$0.75998	$0.90347	($0.14349)	18,116,724	($2,599,514.00)	($233,767.00)	($6,183,290)
May-05	ACTUAL	$0.91584	$0.90347	$0.01237	11,114,633	$137,499.00	$219,212.00	($5,826,579)
Jun-05	ACTUAL	$1.08753	$0.90347	$0.18406	8,176,763	$1,504,990.00	$13,004.00	($4,308,585)
Jul-05	ACTUAL	$1.29689	$0.90347	$0.39342	6,754,764	$2,657,439.00	$76,837.00	($1,574,309)
Aug-05	ACTUAL	$1.24480	$0.90347	$0.34133	6,383,830	$2,178,992.69	($6,376.50)	$598,307
Sep-05	PROJECTED	$1.62579	$0.90347	$0.72232	7,447,000	$5,379,117.04	$0.00	$5,977,424
Oct-05	PROJECTED	$1.75683	$0.90347	$0.85336	9,533,000	$8,135,080.88	$0.00	$14,112,505

Exhibit No.___(HLS-2)

SOUTH CAROLINA ELECTRIC AND GAS COMPANY
PROJECTED COMMODITY COST OF GAS

Month / Yr.	Commodity Purchased Cost of Gas Per Therm	Projected Firm Purchase Therms	Projected Firm Commodity Cost of Gas	Projected Interruptible Sales Therms	Projected Interruptible Commodity Cost of Gas
NOV 05	$1.45862	15,534,000	$22,658,260	18,300,000	$26,692,813
DEC 05	$1.58136	29,009,000	$45,873,728	18,515,000	$29,278,916
JAN 06	$1.28065	41,677,000	$53,373,770	19,661,000	$25,178,916
FEB 06	$1.08923	37,329,000	$40,659,766	19,025,000	$20,722,549
MAR 06	$1.07026	27,498,000	$29,430,041	19,323,000	$20,680,656
APR 06	$0.92874	17,482,000	$16,236,180	16,986,000	$15,775,526
MAY 06	$0.95045	10,064,000	$9,565,320	16,993,000	$16,150,982
JUN 06	$0.98683	7,791,000	$7,688,409	16,606,000	$16,387,334
JUL 06	$1.01594	7,145,000	$7,258,918	16,579,000	$16,843,331
AUG 06	$0.79663	7,118,000	$5,670,422	17,472,000	$13,918,744
SEP 06	$1.02689	7,096,000	$7,286,823	17,342,000	$17,808,355
OCT 06	$1.08972	8,584,000	$9,354,147	18,064,000	$19,684,682
	Total	**216,327,000**	**$255,055,783**	**214,866,000**	**$239,122,804**
	Per Therm		**$1.17903**		

A.	Projected Under-Collection	$14,112,505
B.	Projected Firm Sales Therms	216,327,000
C.	Projected Under-Collection / Therm (A/B)	$0.06524
D.	Projected Firm CCOG	$1.17903
	Projected Firm Commodity Benchmark (C+D)	**$1.24427**

South Carolina Electric and Gas Company
Development of Projected Demand Cost of Gas and Allocation To Usage Groups

Peak Day Allocator Development - 2005-6 Winter	Volume	% of Total
Residential MCF	247,808	73.30%
Small General Service / Medium General Service MCF	76,574	22.65%
Large General Service MCF	13,692	4.05%
Total MCF	338,074	100.00%
@ Purchase Level	344,973	
Convert to Dekatherms @ 1.025 @ Purchase Level	**353,598**	**Peak Design Day Demand**

Projected Demand Costs		
Total Interstate Demand Costs		$22,104,140
Total SCPC Demand Costs		$13,369,343
RFTP Contract of 40410 Dekatherms	40410	$1,596,858
Agreement with Electric sharing 41235 Dekatherms	41235	$2,420,330
Total Projected Demand Costs		**$39,490,670**
Project IMC		**($10,728,093)**
Net Demand Costs		**$28,762,577**

Allocation of Demand Costs to Usage Groups		
Residential @ 73.3%	7330.00%	$21,082,969
SGS/MGS @ 22.65%	2265.00%	$6,514,724
LGS @ 4.05%	405.00%	$1,164,884
Net Demand Costs		**$28,762,577**

Exhibit No.___(HLS-4)

South Carolina Electric and Gas Company
Development of Weighted DCOG Factor and Total Cost of Gas Factor

	Residential	SGS / MGS	LGS
DCOG	$21,082,969	$6,514,724	$1,164,884
Weighted DCOG Factor	**$0.16073**	**$0.08331**	**$0.05863**
CCOG Factor	**$1.24427**	**$1.24427**	**$1.24427**
Total Cost of Gas Factor	**$1.40499**	**$1.32758**	**$1.30289**

DIRECT TESTIMONY

OF

MARTIN K. PHALEN

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2005-5-G

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2005 SEP 22 PM 4: 38
SC PUBLIC SERVICE COMMISSION

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Martin K. Phalen. My office location is 1426 Main Street, Columbia, South Carolina 29218.

Q. **BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am Vice President, Gas Operations, for South Carolina Electric & Gas Company (SCE&G).

Q. **WOULD YOU PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND?**

A. Following my graduation from the College of Charleston in 1977, I was employed with Cummins Engine Company in Charleston, South Carolina, where I held various management and executive-level positions. In 1988, I joined South Carolina Electric & Gas Company. Since that time, I have held executive-level positions in Human Resources & Administration, Operational Support, and, effective May 2003, Gas Operations. I am a former member of the Board of Directors for the Southeastern Electric Exchange, member of the Executive Council for the Southern Gas Association, and am the incoming Chair for the

Executive Committee of the Southern Gas Association's distance learning subsidiary, CTN.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. I will offer testimony regarding the gas purchasing practices of the SCE&G natural gas distribution system for the period under review. I will also discuss the Company's plan to retire its remaining propane air plant facilities. In addition, I will discuss the Company's requested PGA factor. Finally, I will update the Commission regarding the announced plan of South Carolina Pipeline, Inc. (SCPC) to merge with SCG Pipeline, Inc. (SCG).

Q. **PLEASE DESCRIBE SCE&G'S NATURAL GAS DISTRIBUTION SYSTEM.**

A. The SCE&G natural gas distribution system consists of approximately 7,400 miles of mains ranging in size from 5/8 inch polyethylene to 16-inch steel. These mains carry natural gas volumes at pressures typically ranging from 25 pounds per square inch gauge (psig) to 760 psig in order to reliably provide natural gas to the more than 284,000 factories, businesses, and homes in 36 of South Carolina's 46 counties through over 6,800 miles of service lines. Because our system is spread across the state, SCE&G purchases its gas at 193 metered points for delivery from South Carolina Pipeline Corporation, its supplier. The Company relies on SCPC to not only provide consolidated delivery of supply, but also to connect the numerous town border stations throughout SCE&G's service territory.

Q. **PLEASE DESCRIBE SCE&G'S GAS PURCHASING PRACTICES.**

A. SCE&G contracts with SCPC for its natural gas requirements and SCPC provides SCE&G the procurement function necessary for reliable delivery of natural gas volumes. Under Commission approved tariffs DS-1 and DISS-1, SCE&G has contracted with SCPC for a firm contract demand of 276,495 DTS per day. A recently negotiated supplement to the contract, discussed more fully below, will raise this total to 313,188. This volume and other resources ensure that SCE&G can continue to serve its core firm market – residential, commercial, and industrial customers. In addition, SCE&G serves approximately 360 interruptible industrial and commercial customers.

Q. **PLEASE EXPLAIN THE PURPOSE OF THE INDUSTRIAL SALES PROGRAM.**

A. The Industrial Sales Program Rider (ISP-R) is a competitive pricing program for interruptible customers. Customers are allowed to bid a competitive price each month for natural gas based on the price of their alternative fuel source. Approximately 50% of SCE&G's total gas sales are to interruptible customers who have elected to execute interruptible service agreements and have alternate fuels. An interruptible customer relies on an alternate fuel system for two reasons. First, in the event of a curtailment of natural gas service from SCE&G, which is usually due to extreme weather, the interruptible industrial customer may utilize an alternate fuel to maintain operations for the duration of the natural gas curtailment. Secondly, if the weighted average price of gas from SCE&G is higher than the cost of the interruptible customer's alternate fuel, that customer can utilize its less-expensive alternate fuel as opposed to burning natural gas.

Under the ISP-R, the Company is able to reduce its contract mark-up in order to keep these customers on natural gas service even if their alternative fuel price does not allow SCE&G to recover full margin. This helps to offset SCE&G's fixed costs and subsequently lower rates to the firm core market customers. The Commission first approved the ISP-R in 1983 and since that time, the ISP-R has been periodically reviewed by the Commission and its reasonableness has been upheld by South Carolina Courts.

Q. **DO YOU RECOMMEND ANY CHANGES TO THE ISP-R?**

A. I recommend no changes in the way the ISP-R is administered to the customer. However, changes as to the allocation of gas cost and the calculation of margin revenues are recommended. An overview of those changes will be provided in the testimony of Kenneth R. Jackson and a more detailed explanation is offered in the testimony of Harry L. Scruggs.

Q. **PLEASE DESCRIBE SCE&G'S PROPANE AIR ASSETS?**

A. As we have informed the Commission in previous PGA filings, SCE&G has been concerned about its ability to continue relying on propane air. With the Commission's support, SCE&G has been de-rating (downsizing) and retiring its propane air plants over the past seven years. The Ashley Phosphate facility located in Charleston, rated at 2,500 MCFD, was retired in 1998. The Leeds Avenue facility, also located in Charleston and previously rated at 40,000 MCFD, was de-rated to 20,000 MCFD in 1999. The North Augusta facility, rated at 3,000 MCFD, was retired in 2001.

Q. WHAT ARE SCE&G'S PLANS FOR ITS REMAINING PROPANE AIR FACILITIES?

A. SCE&G has the responsibility of ensuring prudent purchasing of natural gas, as well as the responsibility for ensuring reliable and safe delivery. With these considerations in mind, SCE&G has determined that the two propane air facilities have now reached the end of their useful lives and plans to retire both the Leeds Avenue and Lucius Road facilities.

Q. WHY ARE YOU MAKING THESE RETIREMENTS?

A. From a geographical safety standpoint, our two remaining facilities are located in areas that raise concerns. The Lucius Road facility, which has a storage capacity of 1,836,000 gallons of propane, is located within 500 feet of a growing residential community and within 900 feet of the Columbia Canal. Given recent residential development in this area, a failure of this facility could cause severe repercussions to public safety. The Leeds Avenue facility, which has a storage capacity of 918,000 gallons of propane, is vulnerable to hurricanes because it is located within a tidal surge zone. It is also directly below the flight path for the Charleston Airport and Air Force Base.

In addition, from a reliability standpoint, we are faced with operational components of the plants that are antiquated and costly to maintain. Furthermore, changes in the flow patterns on our system limit the amount of propane that can be injected into the system without creating service quality or safety issues. For example, the Leeds Avenue facility, currently rated at 20,000 MCFD, will only be capable of injecting 6,000 MCFD due to changes in flow patterns on the system.

The Lucius Road facility in Columbia, currently rated at 50,000 MCFD, will be limited to 40,000 MCFD due to similar flow pattern issues.

In addition, newer appliances have tight tolerances and do not work as well when propane air is being injected into the system. When propane is injected into the system, customers often complain about how their appliances respond.

Based on the reasons stated above, SCE&G has decided to cease propane operations and retire the Leeds Avenue and Lucius Road propane air plants.

Q. **HOW DOES SCE&G PLAN TO REPLACE THE PEAKING NEEDS THAT WERE SUPPORTED BY THE PROPANE AIR PLANTS?**

A. SCE&G will fill this need through two means. First, SCE&G has negotiated an increase in its existing firm supply contract with SCPC for 36,693 dt per day of the peak design day demand. Of this amount 31,693 dt per day will replace a portion of the peak design day demand formerly met by propane air facilities. The remaining 5,000 dt per day of this increase shall be utilized to meet growth in peak design day from ordinary customer growth.

SCPC informed us that it could not provide the remaining 40,410 dt per day through its existing capacity resources. After considering several options, SCE&G determined the best option was to fill the remaining capacity requirement through a unique sharing of gas supply resources between SCE&G's gas and electric departments. Under a Memorandum of Understanding between the two departments, they will share the cost and benefits of 40,410 dt per day (plus shrinkage) of upstream capacity currently held by SCE&G's electric department. A copy of that agreement is attached to this testimony as Exhibit ___, (MKP-1).

Under the operating agreement, SCE&G's gas department will have available to it 40,410 dt per day (plus shrinkage), only in peak demand periods, to ensure that it has upstream transportation service to meet the last increment of firm demand on its system.

Q. **HOW IS THIS SHARING POSSIBLE?**

A. The Jasper Plant has dual fuel (natural gas or fuel oil) capabilities and on-site fuel oil storage adequate to support this commitment. The peak demand on SCE&G's gas system lasts for a very limited number of days. As a result, Jasper is capable of using fuel oil instead of natural gas during gas system peaks. For these limited periods of time, the gas supply contracts on which Jasper otherwise relies can be shared with the gas department without disrupting Jasper's service to electric customers.

The sharing of gas supply resources is also facilitated by the fact that the gas and electric systems peak during different seasons. Accordingly, even with the sharing, the full amount of the gas transportation capacity is available to the Jasper Plant's needs during the peak electric demand periods during the summer.

Q. **HOW WILL THESE FIXED CAPACITY COSTS BE SHARED BETWEEN THE DEPARTMENTS?**

A. The fixed capacity payments related to 40,410 dt per day (plus shrinkage)of SCE&G's electric department's contract for gas service to the Jasper Plant will be shared 50%-50% between the electric and gas departments. Half of the capacity costs will flow through each system.

Q. **IS THIS ARRANGEMENT BENEFICIAL FOR THE TWO DEPARTMENTS?**

A. Yes. For the gas department to acquire the additional upstream capacity itself, or for it to have SCPC acquire this capacity on SCE&G's behalf, would require SCE&G to pay the comparable cost of fixed upstream capacity at 100% of its cost. The sharing reduces that cost to 50% of the cost of the Jasper fixed capacity, which is significantly lower than purchasing annual pipeline capacity. The electric department is already paying 100% of the fixed capacity costs related to the shared capacity, and so the savings to the electric department are fully half of what it would have paid absent the sharing.

Q. **HOW WILL THE GAS TRANSPORTED USING THIS UPSTREAM CAPACITY BE DELIVERED TO SCE&G'S SYSTEM?**

A. SCE&G has negotiated a contract with SCPC for a Resale Firm Transportation Peaking service (RFTP) in the amount of 40,410 dt per day. This firm transportation contract (which SCPC is filing with the Commission for its approval) will provide SCE&G the right to deliver gas to its system from any of the interstate pipelines connected to SCPC on days when it is fully utilizing its firm bundled-service rights. SCE&G will pay SCPC its standard firm rates for this service.

Q. **WHAT WILL YOU DO WITH THE PROPANE INVENTORY AFTER RETIRING THE TWO PLANTS?**

A. We intend to sell this inventory. While we expect that sale to realize a gain, the amount of that gain cannot be determined until the actual sale takes place. When the sale is made, the expected gain will be applied as a credit to the cost of gas..

Q. **WHAT IS THE NEW PGA FACTOR THAT YOU ARE REQUESTING?**

A. Consistent with the cost of gas methodology contained in the Settlement Agreement in the on-going gas rate case, Docket 2005-113-G, the Company requests that the Commission would set a PGA factor with a Firm Commodity Benchmark for all customers and class specific Demand Charges components. In this PGA proceeding, SCE&G is requesting a Firm Commodity Benchmark of $1.24427, and Demand Charge components of $0.16073 for the Residential Class, $0.08331 for the Small and Medium General Service Classes and $0.05863 for the Large General Service Class. The total factors are $1.40499 for the Residential Class, $1.32758 for the Small and Medium General Service Classes and $1.30289 for the Large General Service Class. All of these are on a per therm basis.

Q. **DID THE COMPANY CALCULATE THE PGA COMPONENT EMPLOYING THE METHODOLOGY USED TO COMPUTE THE PGA IN PAST CASES?**

A. Yes. SCE&G has also filed a PGA component based on the same forecasts and other data, but reflecting the PGA methodology used in past cases. That alternative calculation would result in a PGA factor for all customer classes of $1.46196.

Q. **DO YOU HAVE ANY ADDITIONAL INFORMATION TO PROVIDE THE COMMISSION THAT MAY AFFECT THE COMPANY'S GAS PROCUREMENT IN THE FUTURE?**

A. SCPC and SCG have publicly announced plans to merge to form a new interstate pipeline company, Carolina Gas Transmission Company, Inc. (CGTC). The effect of the merger will be to connect the former SCPC system, which represents 1,436 miles of transmission pipeline in South Carolina, with the LNG facility at Elba Island, Georgia. Because of its interstate character, the new CGTC pipeline will be subject to regulation by the Federal Energy Regulatory Commission (FERC). Consistent with FERC policies, CGTC will no longer offer bundled service after the merger. SCE&G will then begin procuring commodity and capacity from the market to serve its customers in its own name.

Q. **WHAT IS THE CURRENT STATUS OF THE SCPC-SCG MERGER?**

A. SCPC and SCG have posted draft tariffs for the new pipeline on SCG's Electronic Bulletin Board and are currently engaged in confidential settlement negotiations with their customers. The purpose of these negotiations is to resolve as many issues as possible before CGTC's application and tariffs are filed at FERC. Once these negotiations are completed, the results made public, and the likely timing of FERC action on the application is better known, SCE&G will be in a position to understand when adjustments will need to be made in its purchasing practices.

Q. **DO YOU HAVE ANY CONCLUDING REMARKS?**

A. Yes. The primary commitments of SCE&G continue to be the proficiency of our system operations and the safety of our employees. These conditions, in turn, allow our workforce to be free to apply its knowledge, experience, and resources in providing outstanding customer service and nothing less than operational excellence. SCE&G's purchasing practices are indeed prudent; striking a reasonable balance between reliability and price. I respectfully request the Commission approve the new PGA factors requested by SCE&G in this proceeding. I would further ask the Commission to support our decision to retire the remaining propane air plants. I would also ask the Commission recognize the mutual benefits of replacing this peaking capability through SCPC's RFTP request and our internal sharing. Specifically, I respectfully request the Commission approve the prudency of the 50%-50% sharing of the fixed costs related to the operating agreement between the Company's gas and electric departments related to the capacity.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

<u>GAS SUPPLY SHARING BETWEEN THE ELECTIC DEPARMENT AND THE GAS DEPARTMENT OF SOUTH CAROLINA ELECTRIC & GAS COMPANY, MEMORANDUM OF UNDERSTANDING</u>

WHEREAS, South Carolina Electric & Gas Company ("SCE&G") operates both an integrated electric utility (the "Electric Department") and gas distribution utility (the "Gas Department") serving customers in South Carolina.

WHEREAS, the Gas Department has determined that it is necessary to retire certain propane air peaking facilities that have until now provided it with 71,750 dt/day of peaking capacity; and

WHEREAS, the Gas Department's upstream supplier, South Carolina Pipeline Corporation ("SCPC") has informed the Gas Department that it does not have upstream resources presently under contract to serve 41,235 dt/day of the additional capacity requirement incurred by retirement of the propane air facilities; and

WHEREAS, there is currently in force with the Electric Department a contract entitled <u>Gas Supply Agreement Between South Carolina Electric & Gas Company, As Buyer And SCANA Energy Marketing, Inc., As Seller Dated As Of April 2, 2004</u>, which provides for delivery of firm gas transportation and commodity service to the Electric Department's Jasper Generating Station through the interstate gas transmission pipeline operated by SCG Pipeline (the "Jasper Supply Contract"); and

WHEREAS, the SCG pipeline is physically interconnected with the SCPC pipeline; and

WHEREAS, SCPC has the capacity to receive into its system 41,235 dt/day or more of gas on a firm basis at its interconnection with the SCG pipeline; and

WHEREAS, SCPC has agreed to provide the Gas Department with an Experimental Resale Firm Transportation Peaking ("RFTP") Service to deliver 41,235 dt/day of gas from the SCG interconnection to the Gas Department's delivery points on SCPC's system; and

WHEREAS, due to the nature and duration of the peak demands on the Gas Department's system, and due to the availability of alternative fuel capability at the Jasper Generating Station, the Electric Department has determined that it can share with the Gas Department 41,235 dt/day of transportation and supply service under the Jasper Contract for use as a winter-time peaking service to supply the upstream component of the RFTP contract; and

WHEREAS, subject to approval by the South Carolina Public Service Commission, the parties have agreed that a 50%-50% sharing of the fixed capacity costs related to 41,235 dt/day of transportation and supply service under the Jasper Contract is a fair allocation of costs between the two departments for the service being shared;

NOW THEREFORE, the departments enter into the following intra-company Memorandum of Understanding dated this 20th day of September, 2005.

1. Effective December 1, 2005 or such date thereafter as the RFTP agreement becomes effective, the Gas Department shall have the right of first refusal to call on 41,235 dt/day of capacity available under the Jasper Supply Contract during the months of November through April to supply the upstream component of the RFTP contract between South Carolina Electric & Gas Company and South Carolina Pipeline Corporation.

2. The Reservation Charge associated with 41,235 dt/day of capacity under the Jasper Supply Contract shall be allocated on a 50%-50% basis between the Gas Department and the Electric Department for so long as the Gas Department holds the above referenced right of first refusal.

3. Gas Purchases and Scheduling Requirements related to these rights shall be subject to the terms and conditions set forth in the Jasper Supply Contract with the addition of the following provision:

   a. Gas Purchases and Variable Transportation Costs shall be allocated between the Gas Department and the Electric Department based on actual quantities scheduled for the benefit of each.
   b. Any costs associated with imbalances shall be allocated to the department that causes such an imbalance to be incurred subject to the terms and conditions of the Jasper Supply Contracts.

4. In times of anticipated peak demand on the gas system, the Gas Department will give the Electric Department such notice as is reasonably possible of its intent to call on the resources granted hereunder. The Gas Department shall coordinate with the Electric Department to ensure that its exercise of its rights hereunder will conform with the nomination and scheduling protocols of the RFTP Contract and of the Jasper Supply Contract and will cooperate to ensure that penalties, charges and imbalances are minimized.

5. This Memorandum of Understanding may be amended only by writing signed by both departments.

6. The cost allocation provisions of this Memorandum of Understanding shall be subject to approval by the Public Service Commission of South Carolina and the Memorandum of Understanding shall not enter into force until such approval is given.

IN WITNESS WHEREOF, this Memorandum of Understanding has been executed on the date first above written.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
GAS DEPARTMENT

By: Martin K. Phalen

Name: Martin K. Phalen

Title: Vice President

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ELECRTIC DEPARTMENT

By: James H. Landreth

Name: James Landreth

Title: Vice President

DIRECT TESTIMONY OF
MICHAEL P. WINGO
ON BEHALF OF
SOUTH CAROLINA ELECTRIC & GAS COMPANY
DOCKET NO. 2005-5-G

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Michael P. Wingo, and my business address is 1426 Main Street, Suite 155, Columbia, South Carolina 29201. I am employed by SCANA Services Company as General Manager – Gas Supply & Capacity Management.

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS BACKGROUND.

A. I received the degree of Bachelor of Business Administration in Marketing from Georgia State University in 1976. After graduating from college, I was employed by Atlanta Gas Light Company ("AGLC") where, from 1976 to 1998, I held numerous positions with AGLC. In 1998, I became Vice President – Gas Supply for AGLC, where I had responsibility for gas supply, capacity contracting, scheduling of supplies, gas cost accounting, and off system sales.

Q. WHEN WERE YOU HIRED BY SCANA AND IN WHAT CAPACITY?

A. In 2000, I joined SCANA Energy Marketing, Inc. in Georgia as Manager of Operations, and in 2001, I was promoted to my current position, General Manager – Gas Supply & Capacity Management, for SCANA Services Company, Inc.

Q. WHAT ARE YOUR DUTIES AS GENERAL MANAGER – GAS SUPPLY & CAPACITY MANAGEMENT?

A. I am responsible for gas supply and capacity management functions. Specifically, my responsibilities include forecasting and planning, procurement of supply and capacity, nominations and scheduling, gas cost accounting, state and federal regulatory issues concerning supply and capacity, and structured marketing and asset management.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes, I have testified before the Commission on several occasions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Over the last several years natural gas prices have become very volatile. We anticipate that volatility to continue into the foreseeable future. My testimony traces the history of natural gas prices, points out factors which influence those prices, and provides the Commission with market information regarding natural gas prices in the near term.

Q. HAVE NATURAL GAS PRICES ALWAYS BEEN AS VOLATILE AS THEY ARE TODAY?

A. No. The federal government regulated the price of natural gas at the wellhead for many years. While prices were stable and relatively low during government regulation, this price regulation led to the perception that the country was running out of natural gas and resulted in the shortages experienced in the mid to late 1970's. However, the shortages were actually caused by the economics and regulated structure of the gas industry, not by inadequate supply. What had occurred was simple: the cost of exploring, drilling and transporting natural gas to interstate pipelines for delivery to markets exceeded the price that producers were allowed to charge for the gas. Consequently, producers had no incentive to explore for and produce incremental gas supplies.

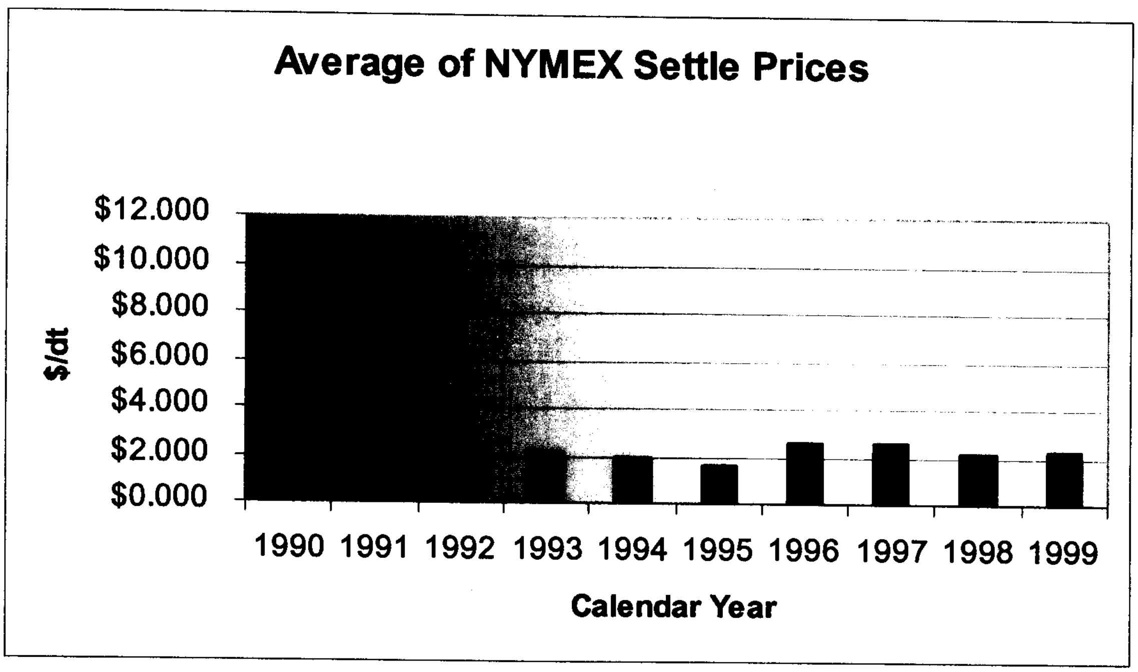
Spurred by the shortages in the 1970s, Congress enacted legislation removing price caps on new natural gas production. Producers then responded so successfully that the market was oversupplied by the mid 1980s, resulting in what came to be called the "Gas Bubble." This oversupply held market prices lower than the expectations of producers who had invested in finding, drilling and producing more gas. New exploration declined and, over time, demand increased gradually bringing into balance supply and demand.

Q. PLEASE EXPLAIN THE RANGE OF NATURAL GAS PRICES THAT CONSUMERS EXPERIENCED FOLLOWING DEREGULATION IN THE 1970s AND THE GAS BUBBLE THAT EXTENDED INTO THE LATE 1990s.

A. As demand increased and oversupply moderated, market prices stabilized and, in retrospect, were quite predictable. The data supporting the graph in Figure 1 set forth below captures each month's closing prices for natural gas as traded on the New York Mercantile Exchange ("NYMEX") for the decade of the 1990s.

The monthly prices were then averaged to determine the average annual cost for each year. For the decade of the 1990s, the graph shows that market prices for natural gas were relatively consistent and stable. The average of the years from 1990 through 1999 was approximately $2.03 per dekatherm ("dt"), with the high year average being $2.59/dt in 1997 and 1998 and the low year average being $1.53/dt in 1991.

Figure 1



Q. WHAT KEY FACTORS INFLUENCE THE PRICE OF NATURAL GAS TRADED ON NYMEX?

A. When the market is balanced between supply and demand, sometimes referred to as market equilibrium, any news, either on the supply or demand side, which tends to upset this equilibrium translates into price movement. One fundamental factor which affects market prices is national storage levels. Storage levels are now published by the Energy Information Administration ("EIA") each week in its National Storage Inventory Report and announced generally each Thursday around 10:30 a.m. Smaller than expected injections into storage during the summer or larger than expected withdrawals from storage during the winter have a tendency to result in prices increasing for natural gas. Similarly, larger than expected injections into storage during the summer or smaller than expected withdrawals from storage during the winter have a tendency to result in prices decreasing for natural gas.

Another factor influencing prices are forecasts of severe weather. Severe weather news, even before there is actual damage, tends to affect the price of gas on the NYMEX. Projections of hurricanes reaching the Gulf of Mexico ("Gulf") coastal area have the general tendency to increase gas prices. Hurricanes generally do not affect prices unless they are projected to enter the Gulf region. Prices generally decrease if revised and updated weather forecasts project a storm's path to miss the Gulf's coastal area where initial forecasts predicted that the storm would threaten the Gulf Coast.

Actual severe weather damage also moves prices higher. Hurricane damage, both to wells or pipelines, reduce the availability of supplies to the market and create upward price movements. Extreme cold weather in the Gulf may cause production equipment at wellhead's to freeze and become inoperable, reducing supplies and causing prices to increase.

The failure of the transportation system also influences market prices. For example, damages to or failures of pipelines through contractor neglect or pipe failure result in losses of supplies to the market, causing upward price movement.

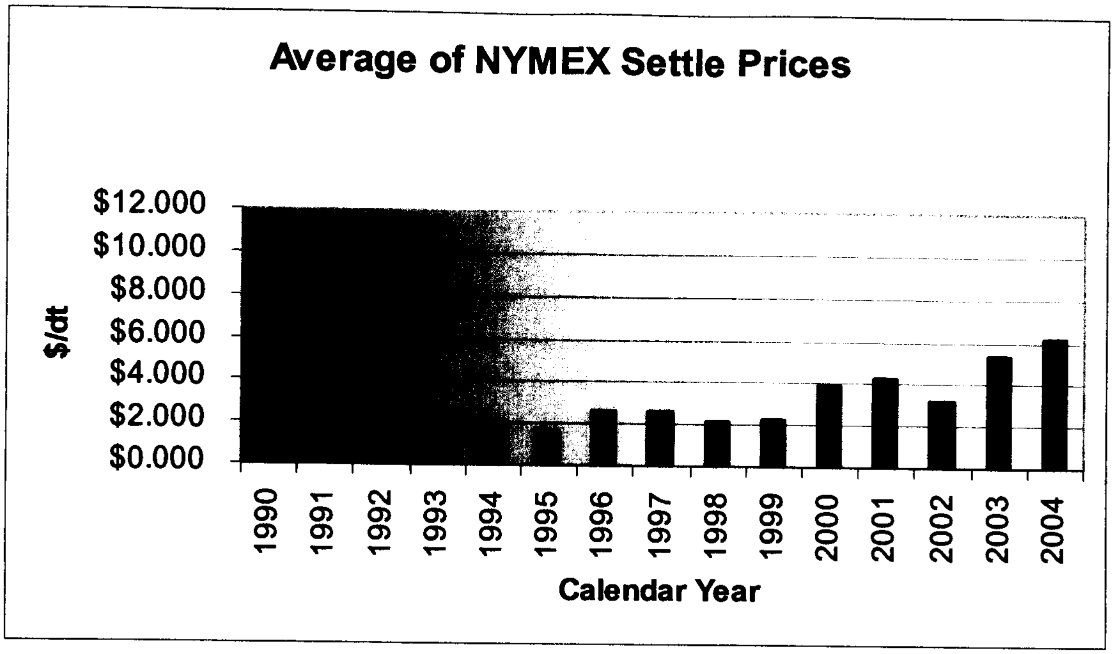
Q. **DID ANY OF THESE FACTORS IMPACT MARKET PRICES OF NATURAL GAS IN THE CURRENT DECADE, CAUSING UNUSUAL VOLATILITY?**

A. Yes. At this time, any disruption in the supply of gas generally results in significant price increases. The first significant instance of this occurred in the winter of 2000–2001 when the country entered the winter with approximately 2.7 trillion cubic feet ("Tcf") of storage inventories. The normal levels are 3.0 Tcf or greater. The smaller beginning storage inventories coincided with extremely cold temperatures in November and December and produced a compounding effect on prices. As LDC's conserved storage inventories to protect against a long winter, the demand for limited wellhead gas supplies increased causing a sharp upward price increase. The effect was a move in first-of-the-month prices from $4.54 in November 2000, to $6.01 in December of 2000 to $9.98 in January of 2001. Nationally, the winter season concluded with .738 Tcf of gas still in storage. During that winter, consumers had used an historically large part of the inventory on hand at the beginning of the winter heating season.

The reverse situation occurred the following winter. During the winter of 2001–2002, market participants were determined not to enter the winter period with less than "normal" inventory levels. As a result, a new storage inventory record of 3.254 Tcf was set going into that winter. However, the winter of 2001–2002 proved to be relatively mild, resulting in demand for wellhead gas for space heating being depressed at the same time that storage inventories were high. The compounding effect of this combination of circumstances resulted in first-of-the-month gas prices of \$3.20 for November 2001, \$2.32 for December, \$2.56 for January 2002, \$2.01 for February and \$2.39 for March. In stark contrast to the previous year, January 2002 wellhead prices were only 25% of the previous January's price of \$9.98. Nationally, the winter season ended with 1.5 Tcf of gas still in storage which was approximately 54% of the inventory on hand at the commencement of the winter heating season.

A comparison of these two back-to-back actual winters shows that prices may vary widely depending upon various factors including inventory, weather, and supply disruptions. In short, during the last four years, the market has experienced the greatest volatility in its history as Figure 2 below shows. From 2000 through 2004, annual prices averaged \$3.89, \$4.27, \$3.22, \$5.39 and \$6.14 respectively. Even the 1990s were relatively stable compared with the volatility experienced for the period of 2000 through 2004.

Figure 2



In comparison, the year-to-date average price for 2005 is $7.84, using actual closing prices through August 2005 plus the closing prices on the NYMEX for September through December as of Friday August 26, 2005. The 2005 price has changed to $8.63 as of September 21, 2005.

Q. PLEASE EXPLAIN HOW THE LATEST NATURAL DISASTER, HURRICANE KATRINA, DISRUPTED GAS SUPPLIES IN THE GULF OF MEXICO.

A. Hurricane Katrina struck the southern United States Gulf Coast on August 29, 2005, and damaged one of our nation's most critical production areas. The hurricane centered in the middle of the Gulf production area and was massive enough to stretch eastward to affect supplies coming up from the Gulf through Mobile Bay, Alabama and as far west as eastern Texas. Southern Natural Gas Pipeline ("Southern") which provides approximately two thirds of the pipeline capacity that serves South Carolina has the bulk of its supplies centered in the Louisiana gulf coast area and has had supply severely limited from the production area of the Gulf.

Transcontinental Gas Pipeline Company ("Transco") which provides the remaining one third of the firm interstate capacity to South Carolina has the advantage of receiving supplies from the south and central Texas supply areas which were not affected by Katrina.

Figure 3a below shows the production areas, storage fields and interstate transportation systems which function together to deliver needed gas supplies to SCE&G.

Figure 3a

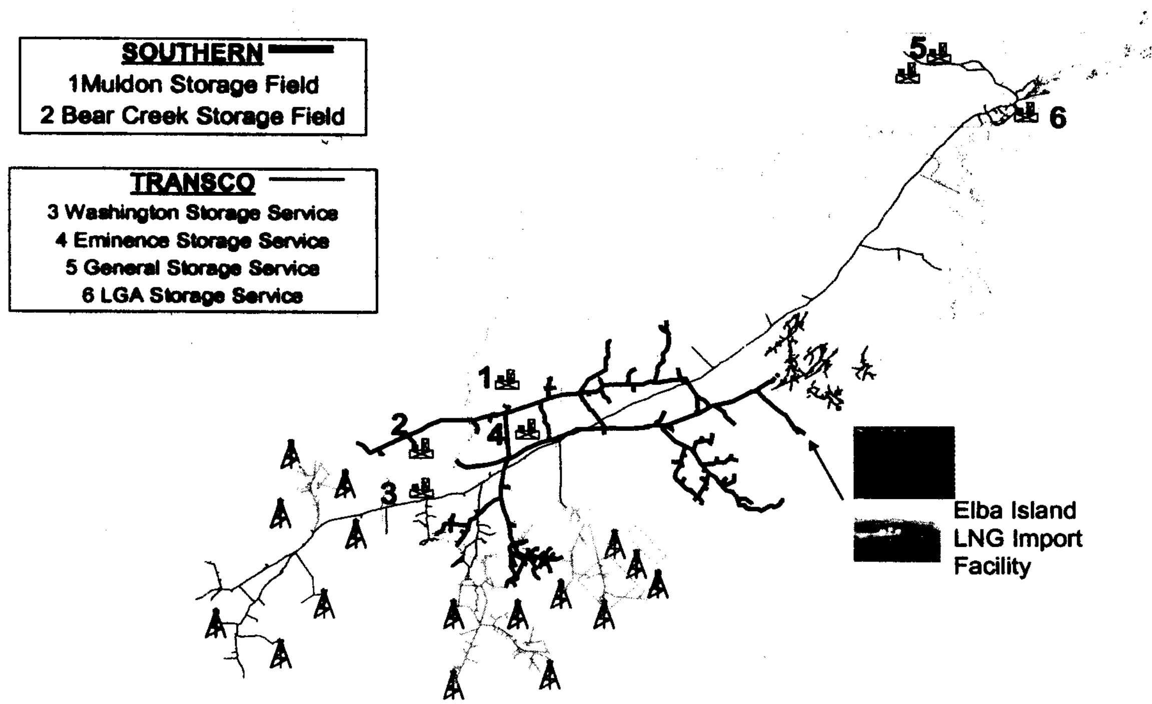
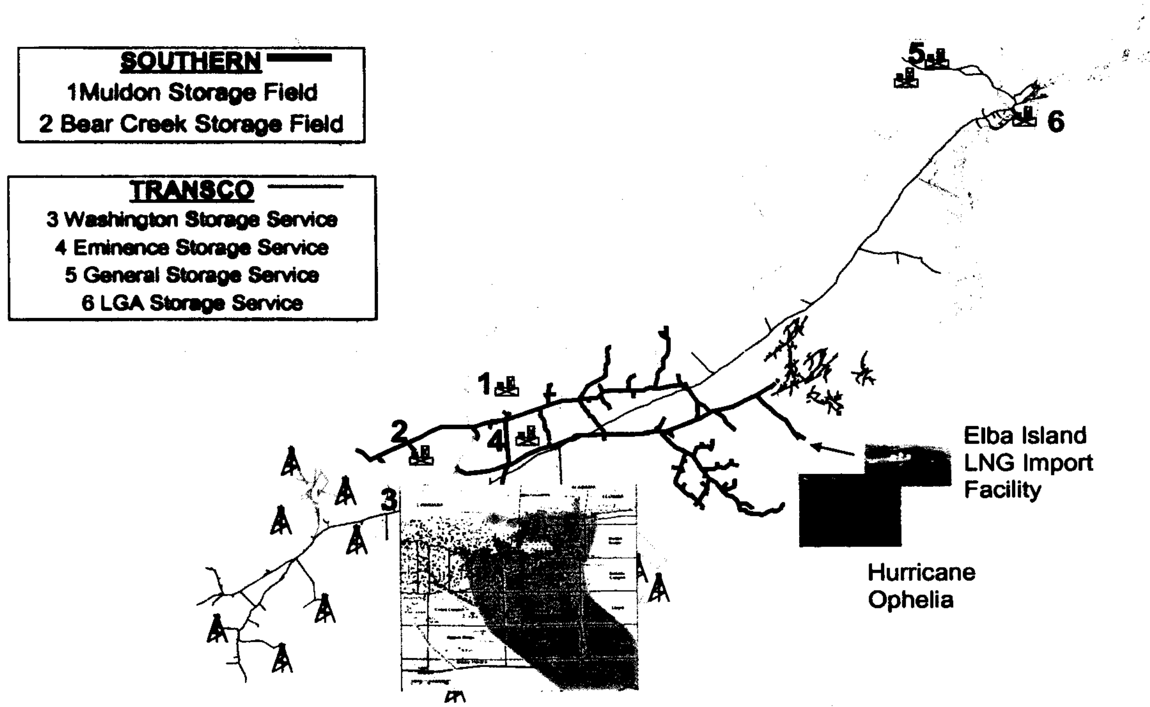


Figure 3b below shows the path of Hurricane Katrina going through the heart of this key Gulf area. The western Gulf was spared by Hurricane Katrina, but projections show Hurricane Rita impacting the Texas production areas. Prices are already reacting to these projections.

Figure 3b

Hurricane Katrina

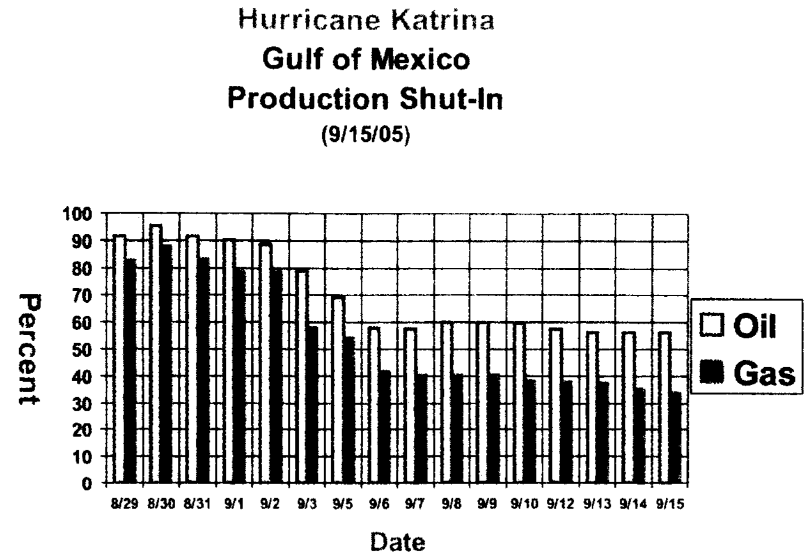


Fortunately for all customers, firm customer demand at this time of year is low as gas is used by firm residential and commercial customers primarily for water heating and cooking rather than space heating. However, interruptible industrial customers are being impacted due to price and availability of gas. Many of these customers have the ability to switch to an alternate fuel source, generally oil. However, the oil supplies and pipeline infrastructure were also damaged by Katrina. As a result, many of these interruptible customers are having difficulty finding replacement oil to replenish their alternative fuel supplies as they are consumed. In response to this disruption, the Commission provided SCE&G with an emergency order, permitting the Company to make market priced natural gas supplies available to these interruptible customers when available as an alternative to a complete curtailment of natural gas.

Q. ARE THE DAMAGES TO THE COUNTRY'S NATURAL GAS INFRASTRUCTURE RESULTING FROM HURRICANE KATRINA FULLY KNOWN TODAY?

A. No. As of the writing of this testimony, we are still awaiting damage assessments from the producers and pipeline companies to determine the complete and long term impact of the damages from Katrina. Mineral and Mining Services reports showed approximately 88% of the wellhead gas supplies normally flowing were unavailable at the height of the disruptions. As damage is repaired, wellhead supplies have steadily returned to service. Nevertheless, Figure 4 shows that 35% of wellhead supplies remain unavailable to customers as of September 15, 2005.

Figure 4



In some cases supply is ready and pipeline damage prevents that supply from moving to market. In other instances, pipelines are intact but the wells are damaged and unable to make supply available. Some gas processing plants are out of commission which impacts the quality of flowing gas. Some compressor stations which keep the gas moving on interstate pipelines are damaged and not operating. In addition to equipment damage, the workforce that lives in this region to make repairs to the infrastructure is coping with their own personal disasters. Given these circumstances, it will be some time before the full damage assessment and long term impact from Hurricane Katrina will be known.

Because firm demand requirements this time of year are relatively low, storage supplies were used to replace wellhead supplies disrupted by the hurricane. As of this writing, enough wellhead supply has returned to serve firm demand, and storage supplies are no longer being used to replace wellhead gas disruptions. However, injections for winter needs have been disrupted and additional gas must be injected into storage to replace the gas withdrawn.

It is instructive to observe how Hurricane Katrina impacted market prices. Thus, the four dates below show market prices one month before Hurricane Katrina struck (July 29, 2005), the day Katrina struck (August 29, 2005), three days after the hurricane struck (September 1, 2005), and as of September 19, 2005 with Hurricane Rita moving into the Gulf. These figures show prices reflecting the weighted average price for the next five winters based on normal winter consumption distribution.

Figure 5

	7/29/2005	8/29/2005	9/1/2005	9/19/2005
Winter 2005 - 2006	**9.136**	**11.786**	**12.290**	**13.728**
Winter 2006 - 2007	**8.775**	**10.219**	**10.313**	**11.279**
Winter 2007 - 2008	**8.310**	**9.368**	**9.460**	**10.048**
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Winter 2009 - 2010	**7.644**	**8.297**	**8.442**	**8.408**

Q. IN ADDITION TO THE GULF OF MEXICO, WHAT OTHER SOURCES OF SUPPLY IS SCE&G DEPENDENT UPON TO PROVIDE RELIABLE NATURAL GAS SERVICE?

A. The primary backup for wellhead supply disruptions is interstate storage. Storage serves several purposes. It is used everyday to balance the differences between demand and wellhead gas purchases by withdrawing or injecting supplies. Further, as with the disruptions caused by Hurricane Katrina, these storage assets are also used to insure reliability by replacing wellhead supplies disrupted by severe weather incidents.

SCE&G's supplier of natural gas service is South Carolina Pipeline Corporation ("SCPC"), which has on-system LNG available for a limited number of days each year. The capacity of these facilities closely matches the short-term duration of the peak demands on distribution companies like SCE&G. SCPC has two facilities, one located near Charleston at the Bushy Park facility and the second located near Aiken at the Salley LNG facility.

Additionally, two LNG import facilities are also positioned to provide incremental supplies to South Carolina. Cove Point LNG facility located in Maryland and Elba Island LNG facility located in Savannah, Georgia are positioned so that gas sales could be made available to South Carolina gas companies.

The LNG import facilities are used exactly the opposite of the on-system LNG facilities. The import facilities are designed to baseload gas each and everyday of the year while the on-system LNG facilities are designed to meet peak demand on the few coldest days of the year. The primary difference in how these facilities are used is based on how they replenish their inventories. The import facilities replenish inventory by ships that bring gas from extremely large foreign liquefaction plants while the on-system LNG plants liquefy gas on site through smaller liquefaction facilities. As a result of the quick replenishment capabilities to the import facilities, they are able to make sales everyday while the long replenishment cycle of the on-system LNG plants limit their use to two or three weeks a year maximum.

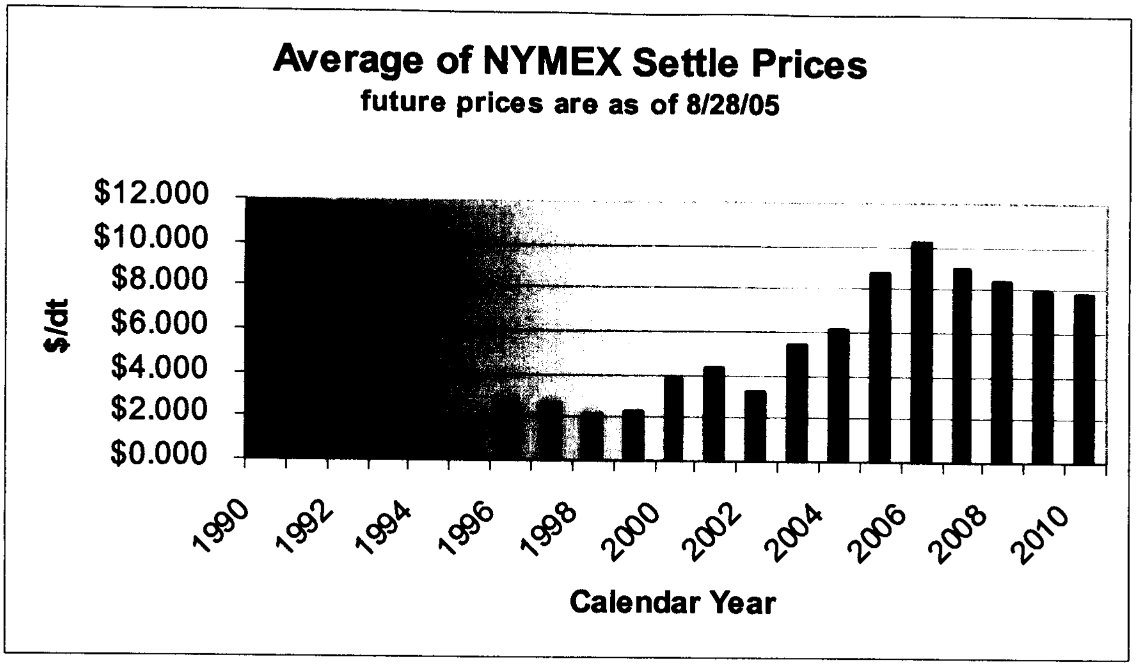
Q. FOR THE NEAR TERM PLEASE EXPLAIN MARKET PRICES FOR NATURAL GAS IN SOUTH CAROLINA.

A. In the near term, market prices are high by historical standards. Figure 2 shows natural gas prices trending upward since 2000. The fact that a full damage assessment from Hurricane Katrina is still unavailable and the disruptions from Hurricane Rita are not yet known will add further uncertainty to the supply picture and tend to maintain high prices.

Weather will also be a determining factor on prices for the 2005-2006 winter season. If storage supplies for this winter period are below normal levels and if the winter is extremely cold in November and December, price spikes and volatility are likely to be experienced.

Looking beyond the upcoming winter season, NYMEX market prices for the next five years (2006 to 2010) are higher, on average, than previously experienced. Figure 6 juxtaposes the relatively stable prices experienced in the 1990s, with the more volatile prices of the NYMEX market in the period of 2000 through 2010. Further, using the futures closing prices as of Friday August 26, 2005 for the years 2006 through 2010, the annual averages are $10.20, $9.04, $8.39, $7.88 and $7.84 respectively.

Figure 6



Q. **PLEASE SUMMARIZE THE KEY POINTS OF YOUR TESTIMONY AND PROVIDE ANY CONCLUDING COMMENTS.**

A. From a reliability perspective, South Carolina is well positioned. Gas supply portfolios are by definition diversified. South Carolina is in the enviable position of having multiple interstate pipelines providing capacity to the state. SCE&G's supplier contracts for wellhead supply from multiple suppliers and also maintains storage service on its multiple interstate pipelines. All of these diverse assets greatly improve reliability.

With regard to natural gas prices, however, it appears that for the next several years the market expects prices to remain high as shown by Figure 6. The market no longer enjoys the surplus supply balance that existed during the 1990s and the current supply/demand equilibrium is easily disrupted, leading to price volatility with a general trend toward higher prices.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes.